Attachment H – Report of Distribution Planning Work Group on DG and Distribution Deferral

The 2005 Annual Report submitted to the Massachusetts DTE by the Massachusetts Distributed Generation Collaborative on May 31, 2005 specified the following objectives that were developed by consensus:

1. Identify and quantify costs and benefits of DG to test the general hypothesis that DG contributes value to distribution planning and meets customer needs by further analyzing the eight distribution planning opportunities and collecting data from existing, pilot, or other DG installations.

2. If the above hypothesis appears to be valid, develop and propose a framework for business and regulatory models that would be needed in order to provide distribution value, meet customer needs, and achieve a societal win/win/win outcome with net benefits greater than costs for all stakeholders.

The Distribution Planning Working Group ("DPWG" or "Work Group") has made sufficient progress toward the first of these objectives, and is pleased to submit this Report to the Department, summarizing what the Work Group has learned to date. The rest of the DG Collaborative's 2006 Report is available at: http://www.masstech.org/dg/collab-reports.htm, including all Attachments.

SECTION 1 – ECONOMIC ANALYSIS TO DATE

The Work Group is submitting to the DTE a separate document prepared by Navigant Consulting, Inc. ("Navigant" or "NCI") under contract with the MTC:

> Distributed Generation and Distribution Planning: An Economic Analysis for the Massachusetts DG Collaborative, January 23, 2006 (the "Economic Analysis", in Attachment G).

All the worksheets prepared by NCI for this analysis can also be downloaded from the following page at MTC's website: Navigant Analysis for the Distribution Planning Working Group.[1] The Collaborative has reviewed with Navigant many of the assumptions, data and worksheets included in the Economic Analysis, but this document is still under ongoing review by Collaborative members and does not represent the conclusions or recommendations of the Collaborative.

The DG Collaborative has spent appreciable time considering the prospect of integrating DG into the utility planning process and has made some progress toward that goal. All of the Massachusetts utilities participated in this effort and provided a significant degree of support for the process. The objective was to evaluate whether and how DG should be integrated into Utility planning procedures, determine what specific potential developments existed in the candidate areas, evaluate the costs and benefits seen by each of the stakeholders affected in the process and consider the technical issues surrounding DG implementation as a distribution system resource. The following sections are a description of the

[1] See link to "Navigant Worksheets" at http://www.masstech.org/dg/collab-reports.htm.

Collaborative's perspective on the successes, concerns, issues, and future considerations related to incorporating DG as a potential planning alternative for distribution system reinforcements.

Two levels of analysis have been undertaken for the Collaborative by Navigant:

- A detailed economic analysis of the potential value of DG for deferral of distribution investments, using utility data on eight distribution locations (the "paper pilots"), and
- An analysis of the costs and benefits of DG that extended beyond distribution deferral, relying on available general sources of information. For the most part, this portion of the NCI analysis (Section 4 of the Navigant presentation) is not addressed in this DPWG Report.[2]

The necessary analysis of technical feasibility and impact on reliable performance of the utility distribution system has not yet been undertaken. Some of the identified issues were discussed in detail at the January 25, 2006 Symposium on Technical and Business Challenges for DG to Play a Role in T&D Planning (see Attachment I).

As described in the 2005 Annual Report to the Department, the utilities offered selected projects as "paper pilots" that were considered appropriate for analysis as theoretical DG based projects. Each Utility identified two candidate projects from projects under consideration at the time that could be suitable for assessment as DG based solutions. This evaluation included a review of all then planned projects, with consideration of the costs and benefits of the traditional solutions. The planning process review offered by utilities focused on the factors that would lead to DG solutions as being competitive with traditional solutions.[3]

The planning process review discussed the salient factors that were considered key opportunities for DG solutions to be effective in addressing distribution system concerns. They included the following factors that would lead to DG solutions as viable alternatives:

1. Avoiding significant capital expenditures - Area supply planning cases where distribution and/or substation supply concerns have a high upgrade cost for limited capacity exposure
2. Sustained deferral value - Locations that have limited and predicable growth allowing upgrades to be deferred for an appreciable duration (i.e. more than 2 or 3 years)
3. Dependable availability - Locations where multiple units or other backup load management can provide support for an area on par with the reliability provided by traditional solutions
4. Controllable response - Installations that are dispatchable or callable by the distribution company and can respond to system conditions in a similar manner to traditional solutions

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[2] Some of the significant costs and benefits beyond deferral have not been quantified in the Navigant work to date, and it is expected that the Work Group will review the analysis again when additional work has been completed.
[3] It is important to note that when the eight circumstances were identified and announced by the distribution companies, the criteria for picking suitable locations where DG could possibly be used in lieu of infrastructure improvement has not been fully developed anywhere in the country. The criteria were the utilities' initial determination at the time. A more thorough review of the criteria might yield a different list of potential sites. However, WMECO submitted the only two scenarios on their distribution system It is also important to note that the specifics of the 'paper pilot' locations change as new loading data and other planning requirements are reviewed following the summer 2005 hot weather.

5. Sufficient supply capacity – The magnitude of Distribution system problems primarily call for MWs, not kWs, of load relief and DG solutions need to achieve these levels

The projects selected resulted in a broad spectrum of distribution problem characteristics and magnitudes ranging from peak overload conditions to substation area contingency overloads and asset replacements. In total there were 8 projects identified for further consideration and analysis. This analysis was intended to address the financial impacts, implementation issues, technical concerns, and procedural aspects of employing DG as a distribution upgrade solution in response to each of the distribution problem cases submitted. A more detailed description of the eight "paper pilots" is provided in Appendix B along with the economic calculations developed to assess their financial performance.

Approach to Economic Analysis

The economic analyses performed for each of the eight projects was based on input from the DG Collaborative and the work plan and EPRI recommendations in Attachment C to the 2005 Collaborative report to the DTE.[4] Navigant Consulting conducted the economic analysis under contract to the MTC, including development of worksheets and discussion of the assumptions with the Collaborative, such as fuel costs, unit installation costs, production efficiencies, and a host of other parameters that were viewed by the group as generally sound and reasonable. An analytical model was created that included detailed calculations concerning rate structures, market penetration rates, numerous other critical factors, and deferral benefits. The deferral benefits were not discounted by the lost revenue the Utility would experience as a result of a DG installation.[5] Had it been included, the net value is typically negative for the distribution company.[6] This effect would only be seen on the Customer Ownership scenario and not the Utility Ownership scenario. In addition, due to all the factors and assumptions involved, the complexity of the model could limit its day-to-day usefulness to other parties.

[4] The EPRI Report in Attachment C can be downloaded from http://www.masstech.org/dg/collab-reports.htm. See also the description of the EPRI DER Partnership in Section 4.5, "Win/Win Business and Policy Frameworks."

[5] See revenue loss estimates in Section 4 of Navigant's Economic Analysis (Attachment G). (This section also quantifies costs and benefits beyond deferral, but most of these estimates are not discussed in this DPWG Report.)

[6] The caveat to this is for NSTAR, which has a limited standby rate; however, most proposed DG installations in NSTAR territory would have been small enough not to incur these standby charges, while still producing a revenue loss.

As noted by Navigant in their accompanying presentation (Attachment G), "this analysis builds on a strong foundation of previous research in DG, particularly in the economic modeling of DG/Distribution Planning and DG Cost/Benefit Analysis, which has been performed over the past two decades. NCI reviewed over 70 reports and presentations on this topic to help develop its analytical framework and assumptions.[7] However, NCI's work is a departure from previous work in several ways, including the following two key characteristics:[8]

- "Produced Practical and Pragmatic Results – Most previous research efforts were theoretical analyses that assessed the value of DG at the macro level. The value of DG is highly dependent on its location within the power delivery system, the customers' needs and the DG units' operation and performance characteristics. This makes it difficult to assess, particularly in general terms, the attractiveness of DG to utilities and customers. Those few studies that have been done at the micro level also, because of a lack of hard data, had to use broad assumptions on utility system planning and costs, and customer economics and behavior. They also tended to focus on a single feeder or location and take the perspective of either the customer or the utility. Because of the lack of hard detailed data, some previous studies have been criticized for using assumptions that are either too optimistic or too pessimistic. In this analysis, NCI had the advantage of getting access to real data from utilities on eight distribution planning opportunities including the utilities' schedules and costs for investment and information on the customers served by these investments. NCI used these data as inputs into proven models that analyze customer and utility economics and project the penetration of customer-owned DG. Because it had good customer data, NCI could more accurately predict the customers' economics using real rate information and reasonable assumptions on electric load and thermal profiles. Hundreds of customer cases were run and the most attractive DG options were identified. The end results are practical and pragmatic, rather than theoretical, and provide a realistic, supportable picture of the value that DG can provide to the distribution planning."

- "Created a Solid Basis for the DG Collaborative's Framework Discussions – If the DG Collaborative finds the general hypothesis, that DG contributes value to distribution planning, valid; it plans to develop and propose a framework for business and regulatory models to achieve a win/win/win outcome. In the past, an effort like this would have been constrained by analyses that only provided qualitative results, or considered only one perspective (that of either the utility or customer), or took an isolated view of a small number of costs and benefits. NCI's approach will allow the DG Collaborative to compare and contrast Customer versus Utility options for DG to find the best frameworks, and also to test hybrid approaches. NCI was also able to build off previous research to provide a comprehensive, quantitative assessment of 17 DG costs/benefits that could be captured by six stakeholder groups. Looking at DG in this manner will allow the DG Collaborative more degrees of freedom in examining alternative frameworks and the confidence to move more quickly forward with workable solutions."

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[7] Navigant's bibliography appears at the end of the presentation in Attachment G and at the MTC website: http://www.masstech.org/renewableenergy/public_policy/DG/resources/DG-Bibliography.htm, and additional bibliographic resources can be downloaded from the following pages at http://www.masstech.org/dg/Benefits.htm:

- DG Benefit and Cost Studies,
- Studies on Economics of Renewable DG,
- Distribution Planning Methodologies for DG,
- Potential Win-Win Business & Regulatory Frameworks, and
- Environmental Benefits and Impacts of DG.

[8] See Slides 3 and 4 of Attachment G.

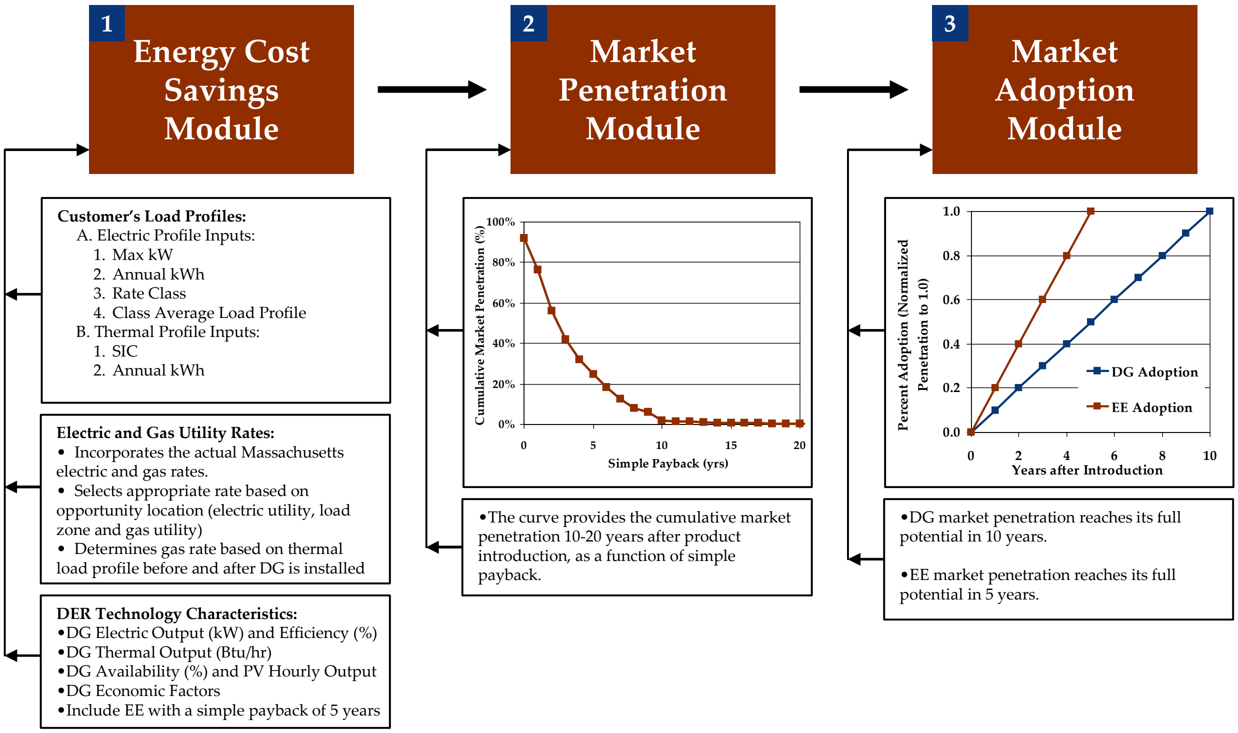
Overall, this analysis demonstrated that each case must be individually reviewed to ensure economic viability. The results also identified that there were significant sensitivities to external drivers such as fuel costs and load growth rates in the problem areas, which could significantly diminish a project's economic viability. The results of these analyses will be discussed in greater detail below.

With this in mind, the fundamental objective of assessing the known costs and benefits for stakeholders based on sample distribution project circumstances was completed and a number of useful analytical tools were developed as part of the process. A description of the analytical tools developed in support of the objective is provided below.

Energy Cost Savings Module for Customer Sited DG

The primary activity over the past year was focused on performing the calculation of costs and benefits. The development of a comprehensive spreadsheet calculation taking into account major economic factors was the focus of the group. This resulted in an analytical tool that included electric and gas rate structures, customer load type specific information, DG and PV unit characteristics as well as a number of other related factors. The tool allowed the Collaborative to review the economic performance of all eight opportunity areas and consider the viability and cost effectiveness of the proposed solutions. Most of the case studies resulted in viable solutions only when customer-owned DG was actively solicited through customer recruitment and utility incentives, and combined with targeted energy efficiency ("EE") and demand response ("DR") programs, also known as distributed energy resources ("DER" or "DE").

According to Navigant's economic analysis, some DG solutions offer payback periods that appeared to be sufficiently attractive to attract investment from some customers, and also offer substantial additional benefits to other ratepayers and society. For key customers in the eight opportunity areas, NCI analyzed a range of DG options (technology, size and operating parameters) to identify the best (i.e. lowest payback) solution, based only on energy cost savings and the installed and operating costs of the DG solution. Of the DG technologies analyzed, the most attractive solutions for customers were combined heat and power (CHP) and photovoltaics (PV). CHP solutions were driven primarily by natural gas engines and run as baseload units that provide electricity and thermal energy. Federal and state incentives drive PV economics and can make DG the most attractive solution for some customers.



Some paybacks less than 4 years were found, even without any incentive to reflect the potential deferral value of the DG (i.e., in the Status Quo Scenario). For example, in the NSTAR Framingham opportunity, paybacks range from 3.7 to 7.5 years for large C&I customers. Across all of the eight opportunities, there was a DG potential of approximately 7 MW for payback periods of 5 years or less, although the majority of customer-owned DG had simple paybacks between 6 and 9 years.

It should be noted that the use of targeted energy efficiency and demand response programs was not subjected to the same level of extensive analysis by Navigant as the DG resources.[9] The costs to implement demand reduction through targeted energy efficiency and demand response programs have, therefore, not been studied. This is discussed below under "challenge # 9" and is an important limitation to the conclusion in the findings of the study. In virtually all cases, an important aspect was the addition of an assumed energy efficiency and demand response to complement the capacity provided by DG and to further improve the economics of the solutions. Until the same rigorous analysis of targeted energy efficiency and demand response programs is done as was done for the DG-only option, it is not possible to conclude that many projects could provide sufficient capacity to meet the reliability needs of the system. In addition, with the addition of DR, deferrals of only 2 years may not be meaningful given the long lead times required for the marketing and enrollment efforts required to implement a robust DR solution.

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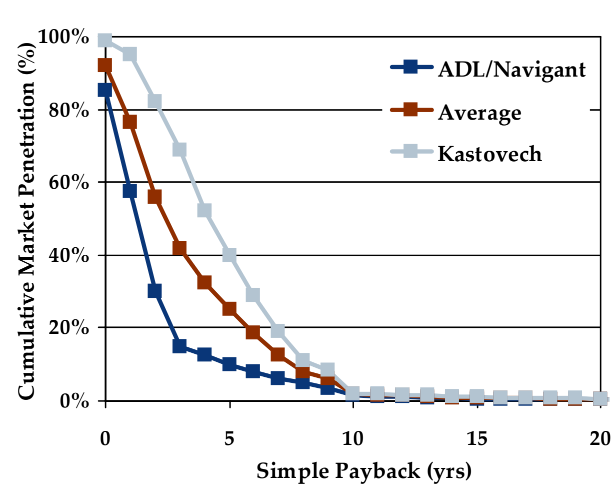
[9] The following acronyms are used in this DPWG Report:
DR = demand response
DER = distributed energy resources
DE = distributed energy
DG = distributed generation.

The analytical model used a number of sub-modules that were an integral part of the calculations. These sub-models included a Market Penetration Module, used to determine the amount of DG potentially available in an area, and a Utility Planning Module, used to assess the economics of deferring utility assets.

Market Penetration and Adoption Modules

The market penetration analysis was directed at determining the amount of distributed generation, energy efficiency and demand response that may be expected for each of the eight case studies based on general customer data (not including market penetration data) provided by the host utilities. The calculation takes into account an array of factors and includes a set of assumptions concerning customer incentives and payback scenarios. Primary assumptions include an estimate that energy efficiency would lead to a 10% peak demand reduction and demand response would lead to a 5% peak demand reduction for those customers participating in the programs.[10] These levels of peak reduction have not been subjected to the same level of scrutiny as the DG-only resources. In some areas, due to extensive energy efficiency programs operating in MA for the past 18 years, the peak reduction from energy efficiency could be much lower. The analysis derived the penetration rates based on typical penetration rate curves and translated this information to the capacity that could be used to mitigate the distribution capacity deficiency in each year of the program.

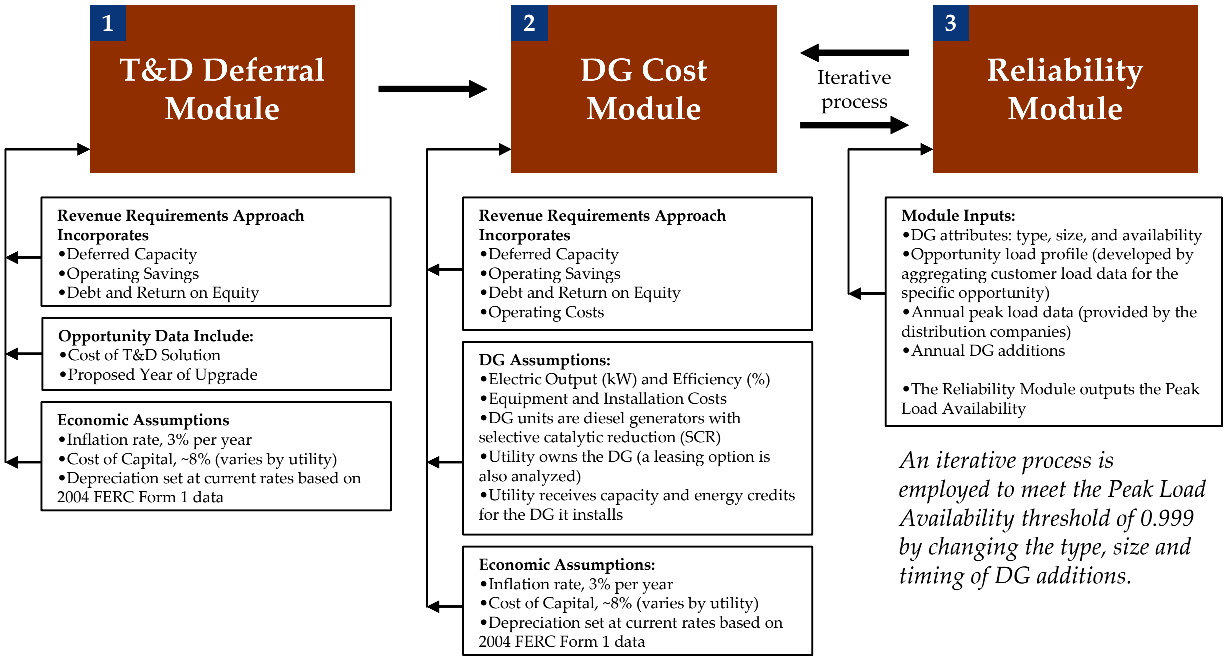
Simple Payback vs. Cumulative Market Penetration



Utility Planning Modules

A set of utility planning modules were developed to review the base economics surrounding use by utilities of DG solutions as an alternative to the typical distribution system upgrade options. These modules are illustrated in the flow chart below. These spreadsheets include computations of the net present value of the cost or savings associated with employing DG as a distribution system resource as compared to a traditional distribution solution.

[10] NCI's assumptions for EE are equivalent to a 2.5% reduction in peak demand by 2010 for the Status Quo scenario. For the Active Customer Scenario, with the combination of incentives and a market transformation effort, NCI's assumptions are equivalent to approximately 2.75% of peak demand by 2007.



The analysis indicates that if a utility were to own the DG asset the net present value would result in savings to utilities for six of the eight cases studied, as presented in greater detail below. An analysis was also done in which utilities lease the DG equipment through a third party. This mechanism may not be a viable approach for Massachusetts utilities as they may be currently prohibited from owning generation in the state, but it may be possible to achieve equivalent economic performance under alternative business models[11]. The number of economically viable DG solutions has been reduced to just three with only two of the three significantly beneficial. At least one of the cases resulted in a level of savings that suggests a DG solution is quite viable as an economic alternative to a traditional distribution solution and would be a good candidate for inclusion in the planning process.

An important point is that there was only a limited review of the adequacy of the DG solutions developed with respect to their ability to meet Utility level performance standards as compared to traditional solutions. An understanding of Utility level performance standard requirements is still not clear. A Peak Load Availability calculation was included (one critical component of reliability),[12] but the analysis of the full spectrum of issues associated with use of DG as a distribution system element remains to be completed.

Scope of Navigant Analysis

[11] Due to timing and format limitations, no details or further documentation was provided for this suggestion that it may be possible to achieve equivalent economic performance under alternative business models, so this remains a subject for future investigation by the Collaborative.

[12] See slides 56 and 86 for diagrams of Navigant's reliability model and slides 66-68 for an illustration of the reliability calculations.

Navigant's summary of the limited scope of its assignment is as follows (slide 2): "The economic analysis presented in this document is based on utility data on eight distribution locations (the "paper pilots"), together with more comprehensive and general research on costs and benefits. The analysis does not attempt to solve technical issues of connecting DG, ensuring reliability and availability, or dispatching and monitoring the resource. It does not address utility revenue losses, regulatory changes that may be necessary to achieve sufficient scale and equitable sharing of costs and benefits, or customer/utility legal, contractual, and regulatory obligations. It does not deal with the regulatory protocols that utilities must follow in distribution planning. Finally, it does not treat the combination of DG with load shedding, energy efficiency, or energy storage opportunities, which are likely to expand its applicability. All these are subjects of a planned "framework for business and regulatory models" that the Collaborative plans to propose in its June report.

Findings Identified by Navigant Consulting

According to Navigant's presentation (Attachment G, slide 2), "the analysis does support the hypothesis that DG can, in at least some realistic situations, contribute value to distribution planning while meeting customer needs. In addition, it is clear that some opportunities exist for implementing DG in a way that can yield benefit/cost ratios >1.0. The models developed herein are expected to be helpful in supporting such planning and assessing such opportunities, by identifying the circumstances and conditions under which DG can provide value to a comprehensive range of stakeholders."

Most of the rest of this sub-section consists of direct quotations from Navigant's presentation (Attachment G). The DG Collaborative takes no position on any of these statements, which represent the conclusions of Navigant and not necessarily the conclusions or recommendations of the Collaborative. Section 2 below presents a series of caveats, concerns, conditions and challenges that the Work Group has discussed relative to these potential findings.

"The results of NCI's economic analyses are promising and the DG Collaborative should continue with its 2005/2006 Work Plan:

- NCI's analysis found that energy customers and the distribution system can obtain economic value from DG at times and in locations where the conditions are right, as described further below, and that the benefits of many DG applications exceed costs for all stakeholders together.
- Specifically, the analysis found some DG solutions which offer payback periods that appeared to be sufficiently attractive to attract investment from some customers, or which offer a positive financial net present value for distribution companies, and which also offer substantial additional benefits to other ratepayers.

"While preliminary results are attractive, there is additional work that the DG Collaborative should perform:

- These analyses confirm that new "business and regulatory models … would be needed in order to provide distribution value … and achieve a societal win/win/win outcome with net benefits greater than costs for all stakeholders," as indicated in the DG Collaborative's 2005 Annual Report.
- In addition, new planning methodologies would be needed to identify the distribution areas where the conditions are right for DG to contribute value, and new technical and contractual solutions would be needed to assure that the DG resources are available and operating when they are needed.

- This analysis also underscored the importance of an integrated approach to encourage demand response and energy efficiency along with DG, because it is not certain in any particular localized area whether enough customers will install enough DG capacity quickly enough to meet distribution needs without those demand-side resources.
- Finally, this analysis confirms that distribution deferral benefits, though significant, generally represent a small share of the overall value of DG. Other benefits that provide the largest values for the electric system and other stakeholders include fuel savings, avoided central plant capacity, emissions and avoided electric system losses.

"Analysis of eight distribution planning opportunities indicates DG could provide distribution value under certain circumstances:

- To address the question of DG's value to distribution planning, NCI analyzed eight distribution planning opportunities under three scenarios – Active Utility, Status Quo, and Active Customer. Based on input from the DG Collaborative, NCI identified three aspects that should be considered when evaluating DG's value to distribution planning – capacity, reliability and economics.
- In the Active Utility scenario, peaking DG could be an attractive alternative to defer distribution upgrades where large investments are required for small shortfalls.
- In the Status Quo and Active Customer scenarios, combined heat and power (CHP) and photovoltaics (PV) can provide attractive solutions for customers based on energy cost savings. Paybacks less than 4 years were found. For example, in the NSTAR Framingham opportunity, paybacks range from 3.7 to 7.5 years for large C&I customers.
- In the Status Quo scenario, without incentives, potential exists for distribution deferral in several opportunities for at least 1 year.
- In the Active Customer scenario, customers are given incentives that vary depending on the cost of the upgrade and the size of the shortfall. The Active Customer scenario also assumed a more rapid adoption (as compared to the Status Quo scenario) of DG through market transformation efforts. With an active program, DG could defer upgrades for an additional year (as compared to the Status Quo scenario) in some of the opportunity areas.
- The most attractive ownership option varies by the characteristics of the planning opportunity. For example, these include the cost of upgrade versus shortfall, customer mix, shortfall as a percentage of load, timing for the upgrade and load growth.

In the Active Utility scenario, according to this Navigant economic analysis, "DG could defer upgrades in many of the opportunities analyzed:[13]

	Active Utility Scenario: Utility Ownership[1]			
	Deferral Period and Economics		Availability in the Last Year of the Deferral	
Opportunity	Deferral Period[2]	Net Savings (NPV)	Peak Load Availability[3]	Total Availability[4]
NGRID Norwell	1 yr	$3,400	0.99989	>0.99999
NGRID Worcester	0 yr	$0	N/A	N/A
FG&E Lunenberg	2 yr	$50,000	0.99932	>0.99999
FG&E Leominster	10+ yr	$160,000	0.99974	0.99994
NSTAR Woburn	2 yr	$500	0.99902	0.99999
NSTAR Framingham	0 yr	$0	N/A	N/A
WMECO Substation	6+ yr	$900,000	0.99896	0.99999
WMECO Circuit	2 yr	$20,000	0.99887	0.99996

For the Active Customer Scenario, according to this Navigant economic analysis, DG at customer sites would be economic for deferral of upgrades for a few years in some of the opportunities with an "active" program of outreach and incentives:

- In the Framingham opportunity (NSTAR), enough DG would be added to defer the distribution investment for 10 years or more.
- In both WMECO opportunities, distribution investments could be deferred for 3 to 4 years while meeting requirements for capacity and availability.
- In one of the FG&E opportunities (Lunenberg), requirements for capacity and availability are met for a 2-year deferral.

However, the technologies analyzed by Navigant were not sufficient to permit deferral in the remaining areas: Worcester (National Grid), Leominster (FG&E) and Woburn (NSTAR).

"The most attractive ownership option varies by the characteristics of the planning opportunity (slide 27). Key drivers for DG/distribution planning attractiveness include:

[13] "For the Active Utility scenario, NCI made reasonable assumptions about DG unit sizes and the year DG units would be installed to meet capacity and reliability needs -- for the deferral period to be met, the annual cost of the DG solution must be less than the annual savings of the T&D deferral, and the DG solution must surpass the Peak Load Availability target of 0.999. Peak Load Availability = 1 - unserved energy at peak hour / peak load (this is a probabilistic calculation based on the historic availability of DG units). Total Availability = 1 - total unserved energy / total load. A more refined set of DG solutions may increase the NPV for some opportunities."

- Cost of Upgrade versus Shortfall is a key driver. Opportunities that require large investments for a relatively small shortfall tend to be more attractive. This is a bigger driver for the Active Utility scenario. It is less of an impact for the Customer scenarios, even though it drives drive the size of the incentive.
- Customer Characteristics are important for the Customer scenarios. The better opportunities (i.e. with lower weighted average paybacks) have large C&I customers with good thermal demand and access to natural gas.
- Shortfall as a Percentage of Load is important for the Customer scenarios. The more customer load and smaller the shortfall the more opportunities there are for DG to meet the capacity needs. Opportunities with a small shortfall as a percentage of load tend to have a greater probability that customer resources can offset the shortfall.

Opportunity	Date of Proposed Upgrade	Average Annual Load Growth	
NGRID Norwell	2009	2.50%	
NGRID Worcester	2006	1.40%	
FG&E Lunenberg	2007	2.96%	
FG&E Leominster	2006	0.00%	
NSTAR Woburn	2006	1.00%	
NSTAR Framingham	2007	0.55%	
WMECO Substation	2010	1.12%	
WMECO Circuit	2009	2.36%	

Deferral Periods		
Opportunity	**Active Utility Scenario**	**Active Customer Scenario (3 yr)**
NGRID Norwell	1 yr	1 yr
NGRID Worcester	0 yr	0 yr
FG&E Lunenberg	2 yr	2 yr
FG&E Leominster	10 yr	N/A
NSTAR Woburn	1 yr	0 yr
NSTAR Framingham	0 yr	9+ yr
WMECO Substation	6 yr	3 yr
WMECO Circuit	2 yr	2 yr

- Timing for the Upgrade is an important driver for the Customer Case. The National Grid Worcester and NSTAR Woburn opportunities start with a capacity shortfall in 2006. This makes it difficult for DG to ramp up to meet the shortfall. In the Active Utility scenario, DG may be installed more quickly.
- Load Growth is an important driver for both cases. Opportunities with slower load growth tend to be more attractive.

"While this analysis has answered key economic questions, others have surfaced:

- Could an Active Customer program entice customers?
  - NCI assumed that DG would be used in conjunction with energy efficiency and demand response. These alternatives are likely to play a key role along with DG in providing distribution deferral. A thorough analysis of these alternatives was not the objective of this report. Further work needs to be done to understand their applicability.
  - It is also necessary to better understand how customers will respond to an Active Customer program, especially given some of the issues above concerning reliability. This work also did not attempt to flesh out a market transformation program. It is not clear what this program would require and if it could be successful in recruiting customers.
- Is the opportunity large enough to cover the additional costs of capturing this opportunity?
  - It is uncertain how applicable the results of this analysis are across the rest of the utilities' distribution systems. The eight opportunities would appear to represent second tier projects (lower priority and likely to be deferred). A screening tool could be developed based on the key drivers that make DG attractive for distribution.
  - This analysis also did not calculate what it would cost to capture this value, since an operational framework is not determined yet. An analysis should be done to extrapolate these results and determine the costs of capturing this value.
- How should the distribution value be shared? NCI made a simplifying assumption that all deferral value, in the Active Customer scenario, would go to the customer. A more practical strategy would have to be developed, keeping in mind the small impact that incentives may have on customer behavior.
- What other analytical frameworks should the DG Collaborative explore? A Hybrid (Customer/Utility) approach should be explored. For example, a utility could install a peaking DG unit at a substation in the short-term while a customer marketing campaign is seeking customers for a long-term DG solution.

"NCI identified 32 benefits/costs for DG. Seventeen of these benefits are relatively easy to calculate and were quantified (Category A). Costs and benefits vary across the eight opportunities; however, the relative magnitude of the costs and benefits is fairly constant. The following table summarizes these costs and benefits for CHP projects:

Range of Total Net Benefits (CHP Installations in all Eight Opportunities)		
Category A Costs/Benefits	**$NPV/kW**	
	Low	**High**
DG Equipment and Installation	(1,200)	(2,000)
Annual O&M Expenses for DG	(800)	(1,300)
Benefits Overhead	(400)	(800)
Increased DG Owner Natural Gas Consumption	(1,400)	(2,800)
Sub-Total: Category A Costs	***(3,800)***	***(6,900)***
Reduced Central Power Plant Fuel Consumption	3,300	6,000
Avoided Central Power Plant Capacity	600	1,300
Increased Reliability for DG Owner	140	250
Locational Installed Capacity (LICAP) Value	0	200
Deferred Distribution System Investment	60	140
Ancillary Services	220	390
Congestion Value	-150	200
Emissions - CO2, NOx & SOx	400	900
Avoided Electric System Losses (1)	600	1,250
Sub-Total: Category A Benefits	***$5,200***	***$10,600***

"The remaining benefits/costs have not yet been quantified, however a qualitative review of these other benefits/costs was performed (Category B). The largest Category B benefits/costs should be quantified next:

- Consumer Electricity Price Protection. By installing DG, DG Owners could reduce their exposure to energy price volatility. In the case of PV, since there is no fuel expense the costs of electricity from PV will not increase over the life of the system due to fuel costs. While a CHP system owner may be exposed to fuel price risk, a CHP owner could switch between producing electricity on-site and taking electricity from the power system.
- Market Price Impacts/Elasticity. The elasticity of demand for electricity supply increases with more DG. Increased demand elasticity can lower electricity supply prices for all electricity

Category B (Qualitative) Benefit/Cost
Health Impact of DG
Increased Emissions (CO2, NOx and SOx)
Noise Disturbance
NIMBY Opposition to DG
Consumer Electricity Price Protection
Power Quality (DG Owner)
Market Price Impacts/Elasticity
Fuel Diversity
Deferred Transmissions Capacity
Reduced Security Risk to Grid
Fuel Delivery Challenges
NIMBY Opposition to Central Power Plants and Transmission Lines
Real Options Value of DG
Support of RPS Goals
Local economic impact

consumers. Since PV is less dispatchable the impact from PV will be lower than CHP.

- Real Options Value of DG. DG could allow distribution companies to make small investments rather than large investments where there is great uncertainty (e.g. load growth). This avoided risk has economic value that goes beyond distribution deferral value and would require a real options economic analysis to calculating and capturing this benefit. Since PV is less dispatchable the impact from PV will be lower than CHP.
- Fuel Diversity. A balanced diverse portfolio of fuel supply provides greater security and increased reliability in the case of a specific fuel interruption. It also helps to address future electricity supply and price concerns. The benefit is greater for PV since it eliminates fuel needs. CHP is fueled by natural gas, but its deployment would reduce natural gas consumption at central power plants and lead to a net reduction in fuel demand.
- Local economic impact. DG can provide high reliable, high quality power that could be attractive for some high technology industries. DG could also attract businesses that have environmental strategies (e.g. greenhouse gas reductions). DG could also provide local jobs for installers, operators and maintainers.

"If additional benefits and costs are considered, DG could be providing net benefits, however there are still issues to address.

- To analyze the benefits/costs of DG beyond distribution deferral, NCI leveraged the results of the eight distribution planning opportunities. The most attractive DG solution (i.e. lowest positive payback) for customers within the eight opportunities was examined. NCI identified 32 benefits/costs for DG. Seventeen of these benefits were quantified. The remaining benefits/costs have not yet been quantified, however, a qualitative review of these other benefits/costs was performed.
- Distribution deferral was not the largest benefit/cost. The largest benefits are fuel savings, avoided central plant capacity, emissions and avoided electric system losses. The largest cost is DG installed costs.
- DG benefits/costs vary widely by technology. For example, CHP has lower installed costs than PV, while PV has no local emissions. The net benefits/costs for CHP were positive for all DG solutions examined. Adding the qualitative benefits would likely make CHP more attractive. PV yields many positive benefits which are offset by the high capital costs. The qualitative benefits/costs (Category B) are all positive for PV and would make PV substantially more attractive.
- DG benefits/costs also vary by location. Some benefits (e.g., distribution deferral, LICAP, and electricity loss savings) are likely to be reduced where there is adequate transmission and distribution capacity. Although reduced, the net benefits/costs would still be substantial and provide net positive impact.
- There are significant benefits beyond distribution deferral that DG could be providing. These benefits are not likely to be included nor captured in traditional distribution planning. Further investigation into DG should be expanded to include these other benefits/costs.
- The results of this analysis is promising for DG; however, this analysis is a simplified approach to a complex issue. There is significant unpredictability and uncertainty in analyzing these benefits. More research needs to be done on some of the more attractive benefits to build confidence in some of these calculations.
- This analysis did not include how benefits/costs would be captured or shared. In addition, to further analyzing benefits, frameworks should be explored that would begin to address how these values would be shared.

"There is still uncertainty; however, additional consideration of DG in Distribution Planning should include other benefits and costs and address the following issues…:

- Is the distribution deferral opportunity large enough to cover the additional costs of capturing this benefit?
    - It is uncertain how applicable the results of this analysis are across Massachusetts. Extrapolating the results would require a market study of the market potential for CHP and PV in Massachusetts. It would also require an understanding of how applicable the eight opportunities are to the rest of the utilities' distribution systems.
    - Also, rather than selecting opportunities that focus on distribution deferral and examining the benefits beyond deferral, the benefits beyond deferral could be used to select other opportunities for analysis. It is likely that opportunities selected to address one or more of these other benefits may provide an even larger net benefit than identified in these 8 opportunities which were not selected to maximize these other benefits.
- How should the value be captured? How should it be shared? NCI did not make assumptions about how the benefits and costs would be captured or how they could be shared. In addition, to further analyzing benefits and market potential, frameworks should be explored that would begin to address how these values would be shared."

Challenges

In the process of assessing the possible implications of the economic analysis provided by Navigant, summarized above, the participants in the Distribution Planning Work Group identified a series of caveats, concerns, conditions and challenges that are discussed in Section 2 below.

SECTION 2 – CHALLENGES TO BE ADDRESSED

This section summarizes three conditions and eleven challenges that the Work Group plans to address over time. Some of the particular next steps to do this are addressed in Section 4 of the 2006 Report of the DG Collaborative, including:

- undertake further work on potential deferral benefits (see section 4.2 of the 2006 Report). This will include holding Technical Design Workshops slated for later in 2006 (see section 4.4, "Workshops to Address the Challenges for Distributed Energy Planning"),
- explore the following areas of potential DG value: impact of DG on constrained areas, impact of DG on market prices, and impact of DG on the environment (see section 4.2.),
- continue and expand the Congestion Relief Pilots funded by the MTC (see section 4.2 and section 4.3.),
- encourage opening of a docket to investigate if utilities can install and own DG as a distribution resource (see section 4.2.),
- using other initiatives, e.g. the EPRI/STAC project, begin discussion among stakeholders on a framework for equitably allocating the costs, impacts and benefits of DG in such a way as to appropriately capture the net benefits of DG (see section 4.2 and section 4.5).

The DG Collaborative has made significant progress toward the goals set out by the Department, and the general consensus was that, subject to the caveats and conditions stated throughout this DPWG Report, DG, in combination with other DER, may be an economic alternative to traditional distribution system investments. Before a program incorporating DG as an element of system planning can be proposed for implementation, a set of technical, legal, and regulatory matters should be more fully studied, and a series of next steps to do so are proposed in Section 4 of the 2006 Report, as noted above.

While the economic analysis to date indicates that DER can provide significant value to energy users and to the distribution system, a set of important challenges must be resolved in order to leverage this potential value. Some of these problems have been identified, and potential solutions have been discussed. The technical feasibility and the cost of such solutions has not yet been determined, and must be considered when forecasting and allocating costs and benefits. There was a general consensus that additional work is needed before utilities can meaningfully adopt DER as a practical solution to distribution system capacity problems. As a minimum the technical issues need to be fully investigated and ways to address each of them, consistent with industry standards, must be developed. Additionally, the economic analysis needs further elaboration and enhancement before it can be concluded that all parties remain whole in the process. Finally, the procedural and regulatory issues need to be more fully explored, particularly as they relate to Utility ownership. All of these items should be considered for inclusion in any future endeavors on this subject.

Three Conditions for Distributed Energy to Contribute Value for Distribution Planning

The key objective for the group was stated in the Collaborative's 2005 Report to the Department. The hypothesis the Collaborative has been considering is not quite consistent with the 2005 Report, in that it has been expanded to include targeted energy efficiency and demand response programs (together with DG, referred to as "distributed energy resources" or "DER") to be implemented along with DG. The hypothesis could be rephrased as "DER can contribute value to distribution planning and meet customer needs."

To help better judge the viability of DG as a resource to the distribution system, a set of conditions or drivers were also developed, as summarized in slide 15 of Navigant's analysis. The three conditions are:

Condition 1: There must be enough DER capacity to meet distribution planning needs. One of the more challenging steps in the evaluation process is determining if enough DER capacity can be made available to satisfy the needs of the distribution system. The process of marketing, enrolling, assessing customer suitability and viability for deploying DER is a complex and time consuming process. It is certainly the most important step and will determine whether or not a DER solution can be formulated to solve the capacity needs. The analysis developed as part of the Collaborative effort will help advance the process for conducting this type of assessment in the future. The analysis concerning DG penetration rates and DG adoption levels is a helpful tool for screening a candidate area for DG applicability to see if this condition can be met and this type of analysis along with one that needs to be generated for targeted energy efficiency and demand response programs should be included in procedures employed by the Utility members.

Condition 2:[14] The reliability impact of the DER solution must be favorable to the utility system. Providing DER solutions that result in the same level of reliability that a distribution system upgrade provides is also an important requirement. Typical distribution system upgrades generally add capacity, flexibility and dependability to the existing infrastructure. DG interconnections for customer-initiated energy management projects do not typically provide comparable benefits for the utility system. In fact, some DG interconnections require additional infrastructure changes to mitigate potential adverse impacts to other utility customers. DER solutions employed as utility planning alternatives must provide equivalent reliability benefits if utilities are to count on them as suitable substitutes for distribution upgrades. The DPWG finds that the impact of DG installations on distribution utility reliability has not been adequately considered in previous analyses when being applied to the utility system as alternatives to distribution system investments. The analysis conducted by Navigant focused on capacity availability statistics, and the calculation tables developed helped derive values useful in the studies. However, this should not be interpreted as an analysis of what is needed to fully meet the operating performance requirements of the utility system, or the resulting level of reliability of electric service to utility customers. A more comprehensive evaluation of the design requirements of DG installations necessary to support distribution system reliability will be needed to fully address these concerns.

Condition 3: The economics of the DER solution for utilities must be favorable. The key objective of the investigations conducted has been to better understand and more expressly determine the economic factors for all directly affected parties when a DG and/or DER solution is being designed.[15] The spreadsheet calculations have provided a formal means to study the economics involved in DG solutions. The calculation leads to the essential question as to who will ultimately receive the economic benefits. This is a difficult question to answer when revenue loss and revenue gains are included in the calculation. Things get even more difficult to sort out when more than the customer and distribution companies are involved in the determination. In addition to the need for the DER

[14] Condition 2 was re-written by the DPWG to expand on the design requirements to support distribution system reliability.
[15] See Challenge # 9 below.

customer to see favorable economics, a number of other parties are also impacted economically and additional work will be needed to fully assess the impact to other parties, not the least of which is the electric Utility involved. The distribution company participants emphasized that "the net value to the Utility must be positive as well" and that the calculated deferral value should be discounted by lost revenue to be an accurate representation of the value stream for utilities.

Eleven Challenges to Address

During the process of more in depth investigations the utilities in the group posed a set of 34 questions and concerns to the Collaborative relative to a series of issues including reliability, planning, costs, emissions, and other potential obstacles to incorporation of DG in system planning. This section presents these and other questions in eleven categories of challenges to address going forward.

In general many of these concerns raised by utilities have not yet been fully addressed through discussion at the Collaborative. These concerns will need to be addressed through follow-on work.[16] It is unclear whether all of the issues are solvable. Specific solutions were not developed in response to each question, and the impact of those solutions on the results of the economic analysis has not been determined. The issues that were primarily procedural and technical concerns will require additional analysis, which, by their nature will call for greater utility and developer involvement.

The Work Group discussed these questions and agreed to focus significant future attention on the following three categories of "Technical Challenges":

1. ***DER Monitoring and Control,***
2. ***DG Behavior on Distribution Systems,*** and
3. ***Utility System Design Changes.***

These three technical challenges are described in further detail below. The following additional challenges and concerns were also discussed by the Work Group as areas for future work:

4. Planning Process: Some of the questions submitted addressed an apprehension over the impact to the planning process. Current planning procedures involve extensive analysis and reporting efforts to identify, recommend and justify traditional distribution solutions. The added endeavors associated with studying DG solutions on top of traditional ones given limited resources is a subject that will ultimately need to be addressed. As a minimum, more expedient means for screening potential DG applications needs to be developed to help limit the cases where such additional analysis would be considered.

5. DER Costs: DG related costs played an important role in the analysis and a number of questions were raised by some parties concerning the basis for these costs. While the studies used cost data that was comprehensive and current, some parties felt that it would be reasonable to review these in more detail and provide or develop a means to make this information more readily available to utilities for

[16] See next steps listed above from the 2006 Report.

use in their evaluations.[17] Specifically, better understanding the costs and timelines required for permitting of DG (i.e. environmental, local zoning, etc.) needs further review and analysis. As mentioned above, other un-addressed technical matters will have an impact on the economics.

6. Marketing Costs: The notable limitations of the analysis begin with the assumptions concerning the marketing and enrollment efforts, the level of customer participation and customer related costs and benefits. These could only be assessed at a high level for the purposes of the study and employed many assumptions about customer characteristics. These factors would need to be calculated at a more detailed level before a definitive conclusion could be drawn for any of the cases studied. This comment only applies to the Customer Ownership scenarios.

6. Net Value to Utility: As discussed above, the deferral calculations did not take into account the lost revenue the Utility experiences when DG in installed. In the Customer Ownership scenario, the net value for distribution companies at all locations would have been negative had this revenue loss been factored into the analysis.[18] Revenues and costs should be shared equitably among the economic stakeholders, providing a net benefit for each stakeholder, including utilities. [19]

7. Emissions: The subject of emissions and the potential limitation emission constraints might introduce was a problem cited. This could lead to unavailability of the DG resource when needed and getting a better understanding of the constraints would be desirable. The Navigant analysis included costs for emissions controls, but the level of and timing of environmental permitting requirements were not rigorously reviewed to determine its impact of the validity of the use of DG. Some utilities believed that only "green power" should have been considered as part of the Planning Analysis.

8. Substantial Deferral Periods: The Work Group felt that distribution planning should in most cases only focus on opportunities to defer distribution projects for significant periods (for example, longer than 2 years). The issue will be addressed more fully going forward.

9. Demand Response and Energy Efficiency: For purposes of Navigant's calculations of the extent to which sufficient distributed resources could be installed in each of the 8 opportunity areas to defer a distribution investment, the Work Group asked Navigant not to assume that DG would be the only such resource, but rather that targeted energy efficiency and demand response programs would

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[17] Navigant observes that the CEC and CPUC data is publicly available and includes hundreds of actual DG installations. NCI cost estimates based on the CEC & CPUC data are significantly higher than the cost estimates provided to the DPWG by the Massachusetts utilities. Substantial time was spent on this and many parties indicated their buy-in on the NCI cost estimates. In addition, a broad sensitivity analysis was performed of installed costs, see page 77 of the NCI report for the range of costs analyzed. Virtually all the published studies on DG costs were reviewed and are posted on the MTC website at
http://www.masstech.org/renewableenergy/public_policy/DG/resources/DistributionPlanning_Benefit-Cost_Studies.htm

[18] See revenue loss estimates in Section 4 of Navigant's Economic Analysis. (This section also quantifies costs and benefits beyond deferral, but most of these estimates are not discussed in this DPWG Report.)

[19] The DG Collaborative recommended in its 2006 Report that stakeholders "begin discussion, ... using other initiatives, e.g. the EPRI/STAC project,... on a framework for equitably allocating the costs, impacts and benefits of DG in such a way as to appropriately capture the net benefits of DG (see section 4.2 and section 4.5). Further information is available at: http://www.masstech.org/dg/winwin.htm.

also be available to contribute jointly to a distributed energy resource ("DER") portfolio along with DG. The hypothesis could therefore be rephrased as "DER can contribute value to distribution planning and meet customer needs." As noted above, given the indication from the analysis of the 8 opportunities concerning the limited stand-alone benefit of DG as a planning resource, continued investigation would be beneficial to fully explore the suggested combination of DG with demand reduction and energy efficiency programs. The Work Group agreed to discuss in greater detail the level of demand reduction that can be expected from targeted energy efficiency and demand response programs. Another important issue that has been identified but not studied concerns how the additional demand response and energy efficiency gains that make up the proposed DER solutions would be realized, how their performance as distribution system resources can be verified, and how they may be confidently incorporated and relied upon in the utility planning process.

10. Representativeness of Sample and Replicability of Results: The relationship between the 8 opportunity areas studied to date and other such potential areas is uncertain, and the selection of distribution projects may represent a limitation of the economic analysis. While these 8 areas were fully considered by the utilities as the most appropriate projects for the case studies, they were only a small fraction of the number of distribution projects the utilities develop each year. There may potentially be a number of other candidates for DG solutions and development of a more comprehensive selection methodology would help address this issue. One subject discussed by the Collaborative was the development of a set of screens that would help select distribution projects as likely candidates for a DG solution. This process is one that is discussed further below and would likely need to be developed in the future. It is important to recognize that the scope of this Work Group has been limited to analyzing the role of DG in system planning based on a limited review of eight specific distribution areas -- one of the first, if not only, review of actual utility projects. The Work Group did not apply the results of this limited analysis in determining the extent to which other similar potential locations for DG implementation exist.[20] The work plan in the DG Collaborative's 2005 Report included some "Supporting Research and Reports" that have not yet been commissioned, including:

- Statewide DG distribution planning assessment, and
- Market assessment of CHP and renewable DG in Massachusetts.

11. Other Challenges: Other important issues that have been identified but not studied include customer and utility procedural matters; and customer and utility legal, contractual, or regulatory obligations, including the utility obligation to provide service and utility responsibilities for service reliability, and including issues about potential utility ownership of distributed energy assets planned to provide distribution support. These issues may underscore ongoing utility questions about the broader cost/benefit outlook for DG as a distribution system resource that have not yet been fully addressed. Certain cost assumptions were included in the economic analysis that were intended to reflect sufficient conservatism to cover applicable unidentified costs and benefits such as these, but they are not based on actual study. These issues will involve additional detailed evaluations. The following list of 9 such challenges for the Work Group to address going forward is another useful set of categories, although some of these points have already been mentioned elsewhere in this report:

a) safe and non-disruptive connection to the distribution system, in network as well as feeder configurations

b) ensuring reliability and availability of the resource, equivalent to conventional service, under all conditions
c) dependable dispatching of DER and monitoring its contribution
d) equitable sharing of revenues and costs among the economic stakeholders, providing an benefit for each stakeholder, including utilities
e) provisions for ownership of DER resources
f) meeting legal, contractual, and regulatory obligations of utilities, customers, and other owners/developers, including provisions for liability protection
g) marketing and regulatory support to achieve sufficient scale of DER to have a demonstrable impact
h) prioritizing among distribution areas, since DER economics vary significantly depending on factors such as load growth rates
i) developing methods to evaluate DER as an effective substitute for traditional distribution system investments and to estimate the period of deferral with confidence

Three Technical Challenges of DER Integration

Some of the 34 questions raised by the distribution companies were technical concerns with respect to reliability. They included concerns that DG installations on distribution circuits could upset the original design and operation, requiring compromises in fault isolation strategies that may degrade service reliability to other customers by increasing areas exposed to interruption and increasing interruption durations. The discussions also included questions about DER dependability, procedures for providing backup and the degree of confidence that can be expected. These are important issues to be addressed as they created uncertainty on how DG would be called upon and what process and obligations the customer had concerning responding to these needs. Creating a high degree of confidence is needed to fully embrace DG solutions and this issue needs to be a high priority in any follow on effort. Because of this, it is unclear as to what extent these other technical matters will have on the feasibility and economics of DG as a distribution system resource. It is likely they will require additional costs to be incurred in order to properly address reliability concerns, and it is possible that certain reliability compromises may not be avoidable.[21] These issues will be addressed as described in Section 4 of the 2006 Report, "Workshops to Address the Challenges for Distributed Energy Planning."

Customer ownership of distributed energy resources that support the Utility distribution system is for the most part uncharted territory.[22] There are technical matters and operating strategies that utilities would routinely employ as a utility-based DR solution that may not be viable for customer-based solutions either due to costs or due to constraints on customer operations. Three areas of concern that can be expanded upon here are (1) the requirements for utility monitoring and control of these units, (2) the operating behavior of the DG units and the utility system when interacting with each other, and (3) the system

[21] Due to timing and format limitations, no rationale or further documentation was provided for this suggestion that certain reliability compromises may not be avoidable, so this remains a subject for future investigation by the Collaborative.

[22] Examples that were discussed include NSTAR's use of generator sets in Allston/Brighton to address congestion and power shortfalls in that area.

modifications needed or changes in service performance resulting from the installation of DG units on distribution circuits. These three challenges are illustrated in the following Technical Challenge Matrix that the Work Group plans to complete, and are described in greater detail below the matrix. There are other more refined technical issues not mentioned here,[23] and those that as yet may remain unidentified due to the limited scope of this review. Many of these issues were discussed at the January 25 Symposium.

Technical Challenge Matrix

		Type of Deficiency	Type of Impact	Summary of Challenge	Potential Solutions
1	**DER Monitoring and Control**	Normal Load Deficiency	Resource availability during heavy load conditions		
2		Contingency Based Deficiency	Dispatchability of DG resource in response to contingency		
3	**DG Behavior on Distribution Systems**	Normal Load Deficiency	DG response to system disturbances		
4		Contingency Based Deficiency	DG availability following a contingency		
5	**Utility System Design Changes**	Normal Load Deficiency	Modifications to protection, control and automation strategies		
6		Contingency Based Deficiency	Alternate power flow issues		

1. DER Monitoring and Control. The first challenge relates to how DG units would be operated as integral components of a utility distribution system, in addition to elements of customer energy management solutions. Utility-based generation solutions would normally include equipment and communication systems that allow a Utility to monitor, start, stop and adjust the output of the generating units. Unit monitoring would include voltage level, reactive output level, fuel level and other performance-based information. This level of control could be cost prohibitive when applied to

[23] Due to timing and format limitations, the authors of this sentence did not offer further details to the rest of the Work Group on the refined issues not mentioned here, so this remains a subject for future investigation by the Collaborative.

a large number of smaller units or it may be overly intrusive when introduced at a customer location. Utility-based units are also designed for operation during periods when they are most needed and generally can be dispatched whenever a problem or potential problem arises. This may not be true for customer-based units, particularly if the units are tied to a thermal output or if the resources are renewable energy type units, which normally do not lend themselves to dispatch control. Any sort of dispatchable control or simply unit status information would require communication strategies to be developed within the utility's existing dispatching functions.

2. DG Behavior on Distribution Systems. The second challenge concerns how well DG units will perform as integral components of a utility distribution system. The Collaborative did not research what, if any, studies have been conducted on how widespread applications of DG on distribution systems will behave.[24] For example, Massachusetts DG interconnection standards require (for good reason) that all DG separate from the utility system circuit they are connected to when there is a fault on that circuit. Implementation of this often causes tripping generating units off line, such that following the event they may not be available as a resource for the utility system they may be supporting. This is a design issue that needs to be investigated and mitigated before such units can be considered as providing support for the local distribution system. An extended implication of this is the need to assess how resilient these DG units will be to remain in operation during disturbances on other portions of the distribution system not necessarily involving a fault on the circuit they are connected to. Again, the design issue is to avoid or mitigate the unwanted removal of DG capacity that is applied to support distribution system constraints. Multiplicity of DG units may not remedy this concern if the behavior is common to enough critical units in the area. If planning takes this into account, it may require significant DG installation and/or distribution system modifications to permit reliance on DG to mitigate utility system constraints. Technical matters such as this could have feasibility consequences that challenge the useful application of DG as a distribution utility resource, or additional mitigation costs that were not directly identified in the economic analysis.

3. Utility System Design Changes. The third challenge recognizes that existing utility primary-voltage distribution circuits and their protection systems are largely designed to be operated radially

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[24] The following references are among those that may be reviewed in greater depth in future work, and that have been posted at the DG Collaborative website, http://www.masstech.org/renewableenergy/public_policy/DG/resources/DistributionPlanning_Process.htm:

- January 2006 -- Case Studies and Methodologies for Using DER for T&D Support Applications: Results from the EPRI White Paper, Bill Steeley, EPRI, Presented to the MA DG Collaborative,
- December 2005 -- Future Grid - Local Area Impacts of DE, EE and RE Impacts, John Kelly, GTI Distributed and Sustainable Energy Center,
- 2005 -- Evans, Peter B. 2005. Optimal Portfolio Methodology for Assessing Distributed Energy Resources Benefits for the Energynet, California Energy Commission, PIER Energy-Related Environmental Research. [CEC-500-2005-061-D]
- September 2004 -- Distributed generation as a means to increase system robustness, and other reports by Distributed Intelligence in Critical Infrastructures for Sustainable Power ("CRISP," led by Energy Research Centre of the Netherlands),
- May 5, 2004 -- Summary of On-Going DG Studies, Snuller Price, E3
- 2004 -- Availability of Dispersed PV Resource During 8/14/03 Northeast Power Outage, Professor Richard Perez at SUNY Albany et. al.,
- August 2003 -- DG Power Quality, Protection and Reliability Studies Report, GE Corporate R&D, for NREL (SR-560-34635): Main Report
- February 2003 -- Evaluation Framework and Tools for Distributed Energy Resources, E.Z. Gumerman et. al., LBNL-52079 .

out from a single electrical source. They are not typically designed to function with multiple electrical sources out beyond the substation supply. Their layout and protection devices are configured to optimize their performance for power flow from only one direction. The installation of other energy sources on a circuit, making it multi-sourced, could require changes to the circuit's protective devices, as well as the sizing, control and allocation of other equipment such as capacitors, voltage regulators, etc. While modifications would be made to meet minimum service and system protection requirements, these changes would add to the project costs associated with certain DG planning options. One example illustrating this is if circuit fusing between the substation and a candidate DG location would have to be replaced with more sophisticated devices to accommodate the DG installation, thereby increasing the cost of the installation. Another example illustrating this is when open time intervals on reclosing devices are insufficient, requiring installation of more sophisticated protection devices to reduce the time needed for DG units to isolate themselves from the circuit, which would further increase costs. Finally, there is also a fundamental requirement to integrate DG units into the designed reliability of the system, which could require additional system upgrades and modifications. The result is that there are numerous and potentially significant costs that may be associated with use of customer owned DG units as distribution system resources, and evaluation of these costs is essential to determining the viability of a DG solution.

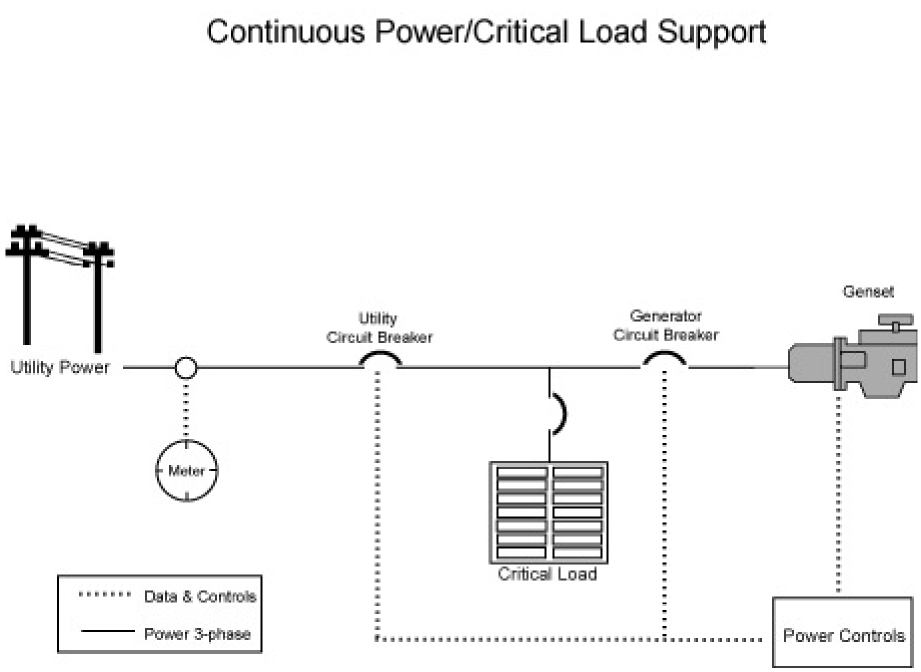
These three technical challenges will need to be considered in the process of moving forward. They should be carefully studied before installation specific investigations are conducted. Each problem noted may be solvable through use of the appropriate design, configuration, equipment and/or procedures, but some may be cost prohibitive or may not resolve all performance sacrifices. For example, an obvious way to deal with a renewable resource such as photovoltaic units would be the inclusion of a battery backup storage system. This would provide opportunity to store energy for use when the customer needs it and provide the resource availability to the Utility when the distribution system needs it. The process for dispatching the backup resource in coordination with the customers energy needs are matters that would also need to be resolved.[25] This is an example of the various technical issues that would need to be included as part of an appraisal of any particular installation.

These technical challenges were identified and discussed during the DPWG meetings in December and January. During the January 11 meeting, the DG providers in attendance were asked to provide some information to the DPWG about technologies available on the customer side of the meter to address some of these challenges, and Northern Power then provided the following information:

[25] For further information on technical approaches to "Large-Scale PV-based Battery Dispatchable Power," see the presentation by Beacon Power to the January 25, 2005 "Symposium on Technical and Business Challenges for DG to Play a Role in T&D Planning" (in Attachment I).

A DG Supplier's View of A Potential Solution to Technical Challenges: Critical Load Support (CLS) and Intelligent Integration of Relays and Circuit Breakers[26]

"In the Critical Load Support (CLS) approach, critical loads are fed from a common bus with dual power supply from the utility and the on-site generation. Should a utility outage occur during normal operation of the generator, the utility multifunction relay opens the utility tie-breaker in as few as three cycles, separating the critical load bus seamlessly from the rest of the facility and failed utility. This also provides an advantage to the utility in that when the system separates from the grid, it takes a large portion of the customer load offline with it. This enables the utility distribution feeder to support a load larger than it could support on its own means, and larger than it could support without the presence of the critical load support system. The customer load will remain islanded on the on-site generation during the outage so that it is not present when the utility feed is re-energized as the generator continues to power critical loads after the separation. The controls will monitor for, detect, and verify stable utility voltage and automatically synchronize and re-close the utility tie-breaker, returning to normal grid parallel operation once again in a seamless fashion.



Source: Northern Power

[26] This sub-section is provided as additional information by Jim McNamara of Northern Power, and does not necessarily reflect the consensus, conclusions or recommendations of the Collaborative. See also the December 2004 article, "Backup Power: Benefits to Expect from a UPS," Jim McNamara, Northern Power Systems," Energy User News, posted at http://masstech.org/renewableenergy/public_policy/DG/resources/DistributionPlanning_Process.htm. See also Attachment I for (a) two Northern Power presentations to the January 25, 2005 Symposium on Technical and Business Challenges for DG to Play a Role in T&D Planning, and (b) email correspondence of Enercon with additional technical information.

> "The CLS system controls sense utility disturbances in a fraction of an electrical line cycle and open the utility breaker to isolate critcal loads from the failed utility . It takes 3-5 electrical line cycles (50 – 80 milliseconds) to open the utility breaker. This separation is typically not detectable to facility operations. Critical loads are carried by the generator through the utility outage. Parallel operation with the utility is restored automatically and seamlessly after utility power is restored.
>
> "Depending on the condition causing the utility outage, the generator may momentarily "see" a utility fault and/or other utility-connected loads, and it must recover from a possible short duration overload. During this time, power quality within the CBEMA curve[27] is not assured as the protected loads will experience a let-through transient, a voltage sag for several cycles in duration and magnitude, depending on the fault condition. If power quality within CBEMA standards must be absolutely guaranteed in all fault cases, additional power conditioning will be applied.
>
> "Protective functions must be present to prevent adverse affects on the utility grid. These features must be designed to meet the specific requirements of each distribution system. The major objectives are that the distributed resource (DR) contribution to a fault on the distribution system is limited, that the generator does not adversely affect distribution system protection coordination, and that the DR does not conflict with utility fault clearing schemes.
>
> "Intelligent integration of protective relays and circuit breakers with the cogen control system are the key to allowing the critical load support concept to work safely in parallel with the utility grid. Equipped with a digital utility multi-function relay, the system is capable of detecting a utility failure within several AC cycles and supporting a defined critical load during the outage. Most distribution systems faults are temporary, and can be cleared by interrupting power and extinguishing an arcing fault.
>
> "Utilities typically employ reclosing schemes in which the power source is interrupted and restored usually from within several cycles to several seconds. When the distribution is interrupted, the DR must come offline to extinguish the fault and preclude the utility from reclosing the generator while out of synchronization, which can destroy or damage generation and/or distribution equipment. The CLS system is designed to isolate within 3-5 cycles when the distribution is interrupted and remain isolated until acceptable utility parameters are again detected, thus avoiding damage caused by asynchronous reclosure."

In response to the above material provided by Northern Power, the observation was made that the systems described above are in use today for customers with critical loads such as financial institutions, pharmaceutical, etc. The average utility customer does not typically have the need for this level of power reliability and, in the absence of a program to encourage design of such systems to support distribution needs, would install a standard DG system without this ability to isolate from the utility during faults. In addition, the costs of this sort of system are higher and have not been fully reviewed.

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[27] CBEMA curve is the Information Technology Industry Council definition of the voltage envelope which typically will not cause interruption of most IT equipment. Information Technology Industry Council is formerly known as Computer and Business Equipment Manufacturers Association.

In order to seek information on some potential solutions to the challenges identified above, a Symposium was held on January 25, 2006, entitled "Technical and Business Challenges for DG to Play a Role in T&D Planning." Attachment I includes the meeting notes and many of the presentations from that Symposium.

These issues will be further addressed as described in the 2006 Report.[28] Specifically, one of the report's recommendations is to "continue and expand the Congestion Relief Pilots funded by the MTC" (see section 4.2 and section 4.3 of the 2006 Report), and the following steps are outlined in Section 4.4, "Workshops to Address the Challenges for Distributed Energy Planning:"

A. Preparatory Activities by Distribution Planning Work Group,
B. Core Technical Workshop Process (including workshops in September and November, 2006),
C. Policy Workshop by the Distribution Planning Work Group (December 2006), and
D. Development of Recommendations by DG Collaborative.

[28] The 2006 Report and all Attachments are available at http://www.masstech.org/dg/collab-reports.htm.